



**ANALYSIS GROUP**  
ECONOMIC, FINANCIAL and STRATEGY CONSULTANTS

# **Allocating Investment Risk in Today's Uncertain Electric Industry: A Guide to Competition and Regulatory Policy During "Interesting Times"**

**Susan Tierney**  
**Analysis Group**

**Boston, Massachusetts**  
**September 2009**

This White Paper was prepared for the Electric Power Supply Association. This paper represents the views of the author, and not necessarily the views of Analysis Group, EPSA, or its members.

**Allocating Investment Risk in Today's Uncertain Electric Industry:  
A Guide to Competition and Regulatory Policy During "Interesting Times"**

**危机**

*Crisis: Danger and Opportunity<sup>1</sup>*

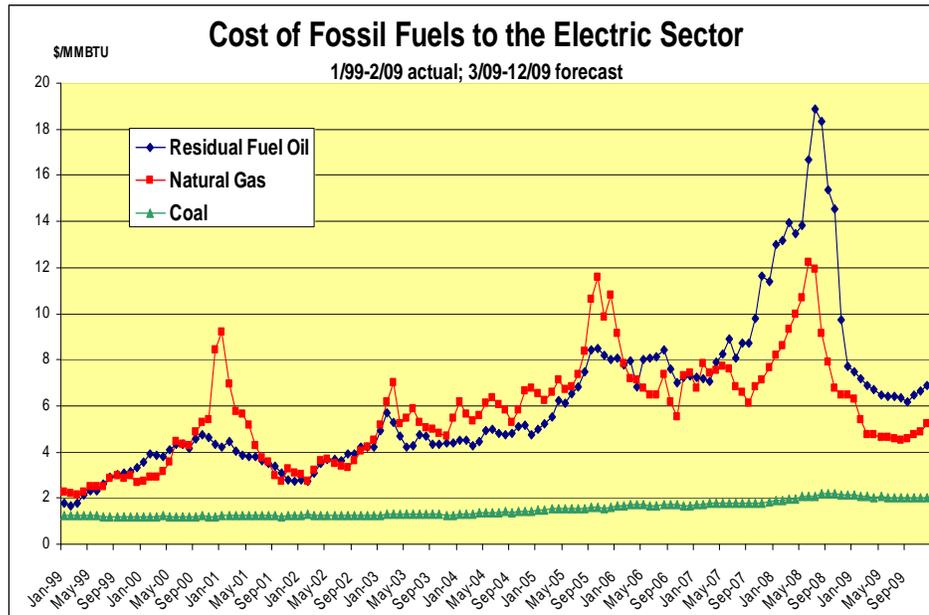
**Introduction**

It doesn't take a crystal ball to know that this is a rough and uncertain time. While no one ever knows how the future will unfold, the severity of today's economic crisis lends a particularly sobering quality to these unknowns.<sup>2</sup>

In the electric industry, this uncertainty creates substantial challenges. This is a notoriously capital-intensive industry – whether the funding goes toward power plant investments, transmission or distribution facilities, large-scale adoption of metering equipment, or installation of large numbers of new solar panels on building rooftops. Capital is committed by many entities including competitive generators, utilities and others. Regardless of who provides it, capital requirements can be daunting.

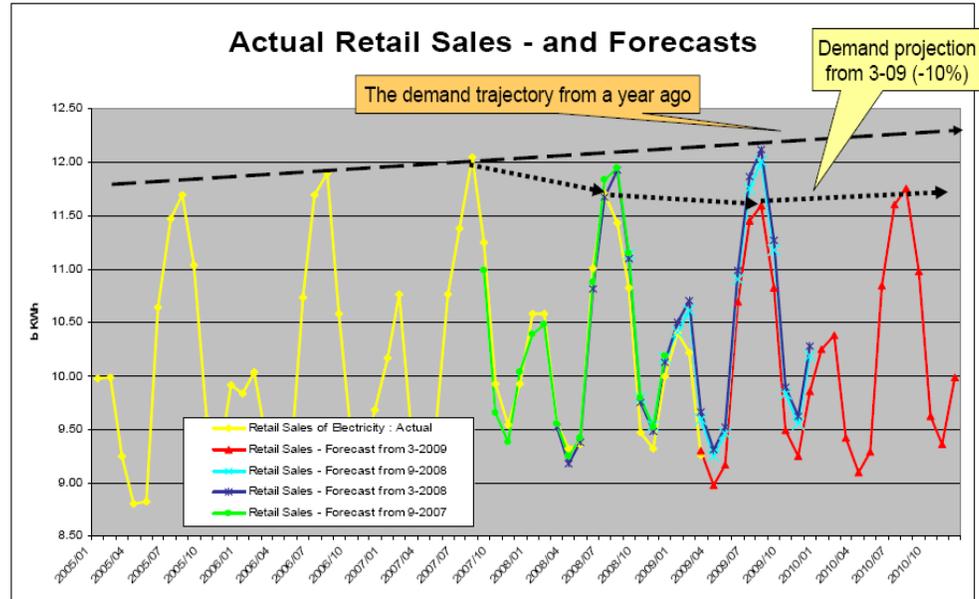
Knowing what type of investment to make is hard enough in more settled times. It is even harder given the various sources of uncertainty that abound at present:

- Will natural gas prices – and wholesale electricity prices in many regional markets – remain low, or rebound with global economic growth? (In the past year, the price of natural gas – which is used to produce one-fifth of the nation's power – rose to all-time highs as well as 5-year lows in the space of a few months.<sup>3,4)</sup>



Source: EIA<sup>5</sup>

- Will demand for electricity rebound after the current economic crisis begins to pass, or will the energy efficiency and demand-response measures promoted by the combined effects of the federal economic recovery program, state policy and programs of utilities and regional grid operators slow (or eliminate) increases in demand in upcoming years? (Forecasts



EIA, Electric Power Monthly data series; Short-Term Energy Outlook

of 2009 power use that were prepared in March 2009 show demand estimates 10 percent lower than forecasts prepared the year before.<sup>6)</sup>

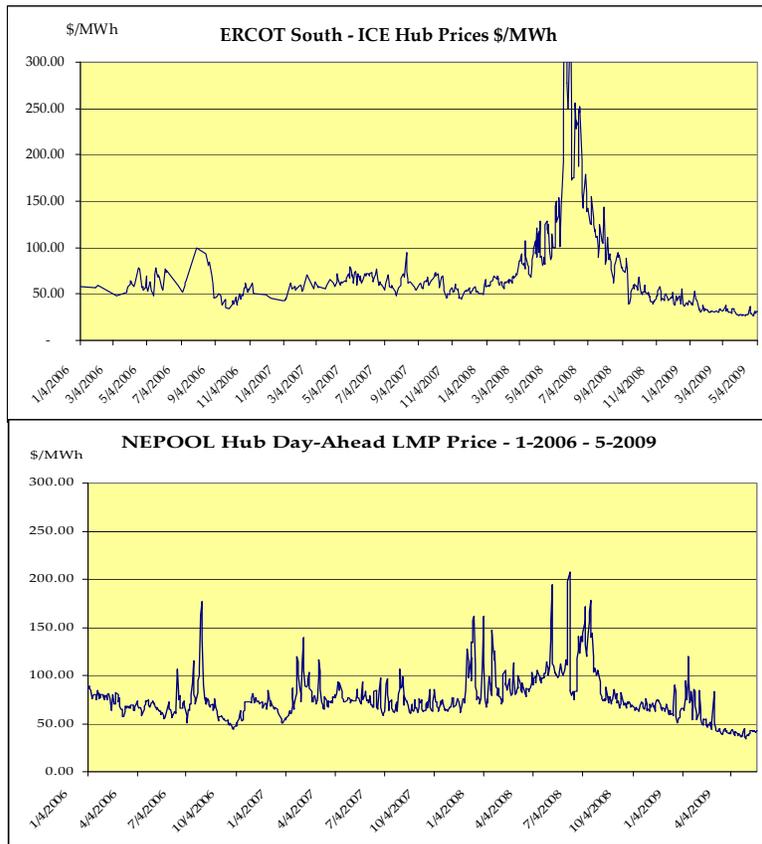
- Will electric companies be able to fund new demand- or supply-side investments in light of balance sheet challenges,<sup>7</sup> current credit market conditions,<sup>8</sup> and traditional regulatory ratemaking policies<sup>9</sup> that need to adapt to today's realities?
- What form will national carbon controls take by the time they impact the economy – given that their timing and shape are affected not only by congressional debates that are still underway<sup>10</sup> but also by countless implementation decisions that will need to be made over the years following passage of new legislation? Will its provisions create the right conditions to induce new low-carbon technologies into the market place?<sup>11</sup>

These are indeed “interesting times.” As the Chinese say each time they use the word “crisis,” this is both a challenging and opportune moment. President Obama referred to those challenges and opportunities when he spoke of the economy and the electric system on his inaugural day in January 2009,<sup>12</sup> and then again when he addressed a joint session of Congress a month later.<sup>13</sup> The American Recovery and Reinvestment Act is providing billions of dollars for investment in energy technologies. If the President accomplishes his goal, this will be a down payment towards larger changes in the electric industry, affecting demand for electricity, the robustness of the electric grid, and the ability of low-carbon and renewable technologies to move into markets.

These conditions pose a complicated set of options for electric companies and for regulators. How does one create an appropriate policy atmosphere in the face of so much risk and uncertainty?<sup>\*14</sup> An understandable response would be to retreat to the familiar. But what is safe ground in today's environment? I offer two suggestions for how regulators might approach these issues: First, ride the horse you're on (or, as Abraham Lincoln would say, don't change horses midstream). Second, extract the best from principles of competition and regulation.

**Ride the horse you're on**

In recent years, there have been debates in policy circles and in the industry more generally on whether those parts of the country that restructured their electric industry would be better off returning to a more traditional industry model. Although political pressure (especially among elected officials) to do so has ebbed somewhat with the decline in natural gas prices and the related drop in wholesale electricity prices, there are still rumblings in various corners about this issue. (See figures to the right, which illustrate the variation in electricity prices over the past several years, using Texas (ERCOT South) and New England (NEPOOL) as examples.)



Source: EIA, Wholesale Market Data, <http://www.eia.doe.gov/cneaf/electricity/wholesale/wholesale.html>, accessed on June 5, 2009.

\* In a separate document ("Appendix Figures for the Allocating Investment Risk in Today's Uncertain Electric Industry: A Guide to Competition and Regulatory Policy During "Interesting Times" (September 2009), I have compiled information that compares historical forecasts of important variables (like demand, fuel prices, construction costs, and so forth) that affect investment decisions, with information about the actual trends in the variables of interest over time. Please see the EPSA website to review this separate appendix.

At this particularly turbulent time in our industry, it is more important than ever to do things to raise investor confidence in ways that will produce benefits to consumers. In this context, it is not helpful to keep debating the “markets versus regulation” question. All else equal, regulatory uncertainty and political risk will always put pressure on investor confidence. There is already enough uncertainty for all of us to deal with,<sup>15</sup> without adding to it by continuing to debate whether a state should dramatically alter the structure of its electric industry. That is why I suggest that each jurisdiction “ride the horse you’re on” and then make good use of the policy tools of competition and regulation in order to provide the best sustainable, long-term outcomes to reliably serve consumers.

### **Extracting the best from competition and regulation**

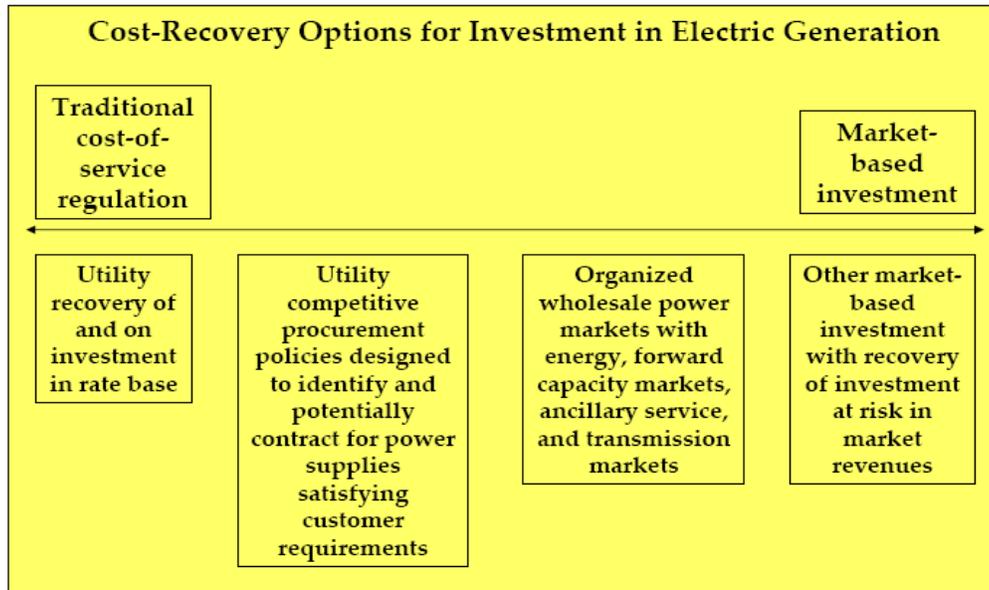
For many decades, the electric industry relied principally on traditional cost-of-service regulation. More recently, the industry has also incorporated a number of regulatory approaches built on competition. Many years of experience provide instructive lessons about why it is important to rely on the best of both market and regulatory mechanisms.

We know that it is important to structure both markets and regulation using sound policy design. On the traditional ratemaking side, we learned lessons from problems caused by after-the-fact prudency reviews of massive nuclear investments in the 1980s, and we are learning to align incentives with desired results as we move toward reliance on revenue decoupling as a companion to energy efficiency initiatives by utilities.<sup>16</sup> And in markets, we better understand the importance of market design after the California electricity crisis in 2000-2001, and as we see the benefits of competition for improved power plant performance,<sup>17</sup> and in the results of competitive power procurements.<sup>18</sup>

Continuing on a regulatory path that attempts to assign risks to those parties best suited to best manage them is a sound rock to stand on. This is hardly rocket science, but it is still worth remembering that this will give electricity customers the benefit of the best of both market-based approaches and regulation.

There are many examples of well-functioning market designs in the space between a pure traditional cost-of-service regulatory framework and a pure merchant model for generation investment. While there are various designs along the spectrum, there are two strong, well-functioning approaches in the middle: energy auctions administered by regional transmission organizations, and competitive solicitations carried out by load-serving entities such as electric utilities. Both operate pursuant to rules established by regulators. And both rely on competitive pressures on suppliers to

discipline costs, and the oversight of regulators to ensure fair and open competition. In the following section, I review the two bookends and the two “middle” approaches.



### These Four Cost-Recovery Options

The starting point for discussing these investment recovery options is to remember the importance of establishing appropriate regulatory incentives for disciplining costs. In well-performing markets, firms and individuals have incentives to reduce costs and make appropriate investments because they can realize the consequences of their decisions.

In the electric industry historically, regulation arose because various conditions<sup>19</sup> prevented reliance on market forces. Regulated cost-based rates serve as a second-best proxy for price in the absence of competitive markets.<sup>20</sup> In the presence of markets, we can shop around for what we consider to be the best deal, knowing that suppliers are competing with each other for our business.

Thus, the electric industry has two archetypal models for inducing power generation investments. On the one hand are power plant investments and operations under traditional cost-based, rate-of-return regulation of utilities; on the other hand, investments and operations of power plants occur under market-based rates. These are not the sole models for investment, but rather serve as “bookends” for other possible arrangements between investors, utilities, regulators, and third-party suppliers. In practice, many utilities use competitive markets as part of how they approach investments and operations under regulated rates.<sup>21</sup> And many third-party suppliers rely on contracts with regulated utilities as a fundamental element of the suppliers’ ability to bring market-based products to fruition.<sup>22</sup>

Still, focusing on utility rate-base investment and merchant third-party market-based investment as two ends of the spectrum (shown in the figure above) allows us to examine important issues about how these alternative arrangements allocate the risks between the investor, the utility, the regulator, and the consumer. The different regulatory/ financial incentives involve the following elements:

- Recovery of and on investment subject to regulatory approval. Under this classic model, the utility undertakes an investment and construction program (with more or less regulatory review of its resource plans). As the project becomes ready to provide service to consumers, the utility seeks to include the new investment in rate base – and to charge customers rates that allow recovery of and on the investment. The regulators then perform an after-the-fact review of the prudence of the investment, and determine whether it is “used and useful.” Having been approved by utility regulators, such new investment is folded into the utility’s revenue requirement at the next rate case, and rates are set to recover these new costs (along with other costs in the new period).<sup>23,24</sup>
- Utility’s Power Purchase Agreement with an Independent Supplier. Instead of building its own power plant, a utility may contract for wholesale power supply from independent suppliers through a long-term agreement. Such agreements may arise from bilateral negotiations or competitive procurements. Many formal competitive procurements are subject to oversight and rules of regulators. By design, competitive procurements for incremental resources are intended to be the means by which a utility identifies the “best” resource option to satisfy a particular supply need (e.g., dispatchable intermediate supply, or peaking capacity, or renewable energy credits).<sup>25</sup> If the utility selects a third-party supply offer (as opposed to building its own plant), a contract between the utility and the supplier serves as the basis for allocating specific risks between the investor (the power supplier) and the utility (who buys the power). Typically, the costs associated with contracted-for supplies are recoverable in rates, often through a mechanism that passes costs through to consumers (as in a fuel-adjustment clause or similar cost-recovery mechanism). (Note that another form of competitive procurement exists in states with restructured electric industries with distribution companies without their own power supply; here, the utility may rely on competitive procurements to procure wholesale supply for basic service customers.)
- Investment within Organized Wholesale Power Markets. Some companies have been able to support investment in generation through their participation in various auctions in power markets administered by Regional Transmission Organizations (“RTOs”). Although the specific details of RTO-administered markets vary across regions, some (e.g., PJM, ISO-NE) involve a combination of markets (e.g., day-ahead and real-time energy markets, forward capacity markets, various ancillary

service markets, transmission congestion contracts) that support plant investments. Some take the form of a financially binding long-term agreement (such as a multi-year transmission congestion contract, or a three-year forward capacity contract entered into as a result of a capacity auction), while others are structured in the way of short-term performance-based auctions (e.g., a financially binding day-ahead hourly energy auction).

- *Merchant Plant Development.* Under a pure merchant model, a third party (including in some cases a utility's unregulated affiliate) makes an investment in new generation facilities outside of a regulated cost-recovery framework. These investments are undertaken without the expectation of revenues obtained through regulated rates – whether through the utility's regulated ratebase, or through a contract that relies on recovery from a utility's customers, or through the regulated tariff of a regional transmission organizations). These investments may rely, however, on financial support or contractual commitments from unregulated retail providers,<sup>26</sup> or on the strength of the developer's/investor's balance sheet.

### **Allocating Risk – How It Works Under the Different Cost-Recovery Options**

These various approaches involve different arrangements under which investment risk is borne by consumers.

For example, after-the-fact review of utility power plant investments typically involves having the utility bear certain investment risks during the course of the planning, development and construction process. In the classic form of “prudency” reviews, the regulator assesses the utility's conduct after the fact, and uses adjudicatory proceedings to determine the extent to which appropriate and effective efforts were made by the utility to prudently manage such costs up to the point when the plant is ready to enter commercial operation and the utility seeks to recover investment costs in rates. While there are notorious examples of investment disallowances during the nuclear era, more commonly state and federal utility regulators have allowed utility investment into rates once it is used and useful.<sup>27</sup>

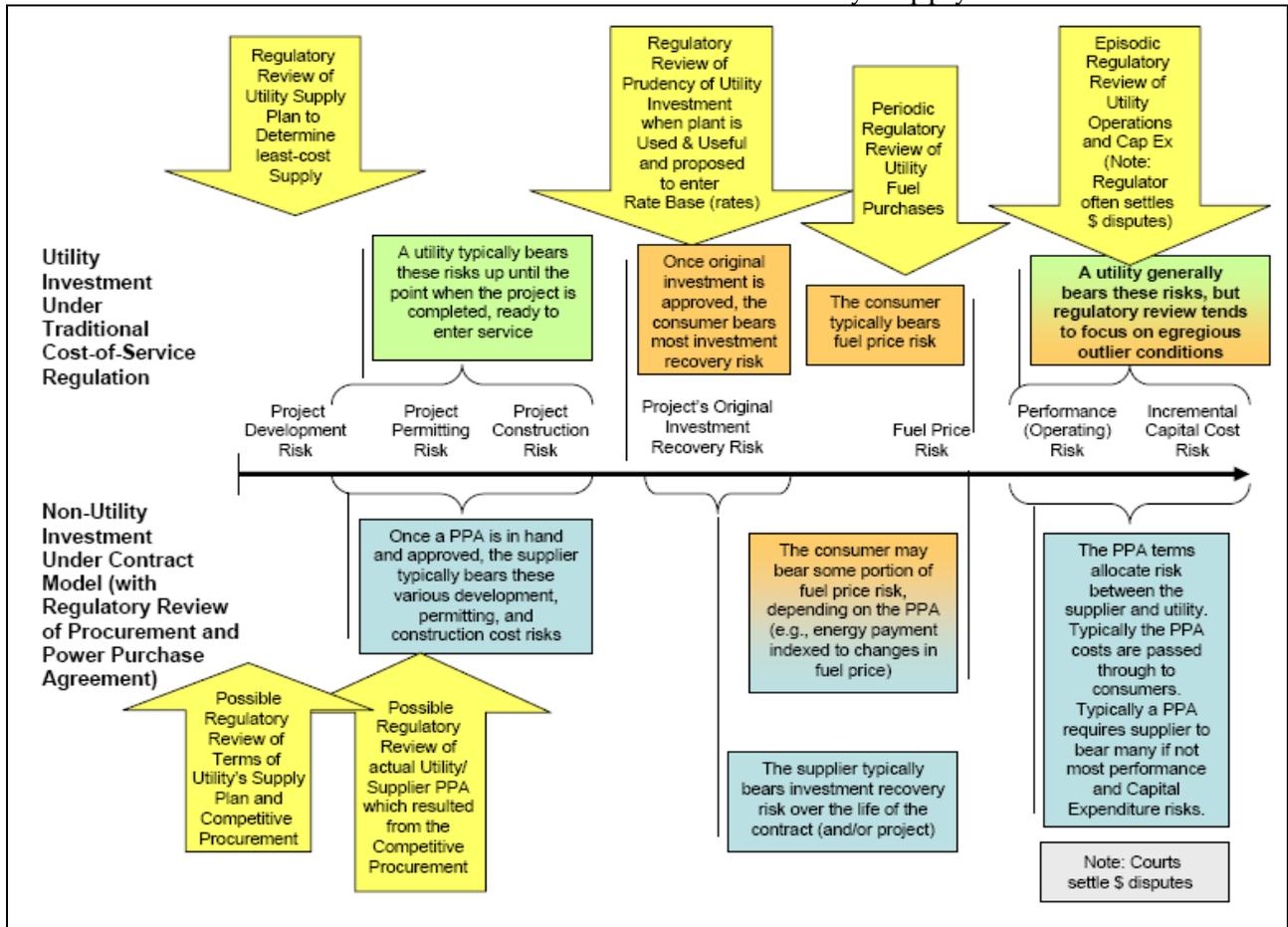
By contrast, a utility contract with a competitive supplier typically fixes the terms of payments and requires the supplier to bear many project risks, including development, permitting, construction-cost, and operating risk. Such agreements may allow certain elements of supplier compensation to vary over the life of the delivery of services under the contract, such as when construction payments are pegged to price indices that affect construction materials, or where energy prices are pegged to fuel price indices. Either way, because such contractual terms allow the third party supplier to retain profits from the reduction of costs, it typically provides an incentive to undertake efforts to lower these costs, and the supplier's original price was

determined through a competitive process that yielded the lowest cost or best value to consumers. A performance-based contract can also insulate consumers from various risks associated with cost overruns and performance problems that might arise over construction and/or operations of the plant.

In both of these different approaches (e.g., rate basing of utility investment in plant, versus power purchase agreements between the utility and a supplier), regulators maintain oversight of any costs that may be recovered from ratepayers. Traditional cost-of-service review provides regulators with an on-going role in determining how the costs associated with the facility's construction and operation are passed through to consumers in rates, with difficult choices on whether to allow recovery of cost overruns by the utility when they occur.<sup>28</sup> Investment risk is usually settled at the time the utility presents the investment to regulators for approval to go into rates; regulatory treatment of operating costs, fuel cost and incremental capital expenditures for the facility may occur over the life of the unit. By contrast, utility purchase power agreements with suppliers attempt to fix the terms of payment in advance (e.g., prior to the delivery of third-party supply or the utility's investment); the regulatory review occurs at the time the utility presents the contract to the regulators for approval. This approach shifts substantial construction, fuel and operational risk away from consumers and therefore can provide important benefits to consumers given the many types of uncertainties facing the industry described earlier. Use of power purchase agreements does, however, involve some degree of mutual commitment on the part of regulators and utilities to live by the terms of potentially long-term agreements reached at the outset of a new investment. To be effective, the investor's commitment to bear the risks associated with project development must be matched by a corresponding commitment by the regulator to abide by the agreement regardless of external market outcomes – just as the third-party supplier is bound to the terms of any contract, for better or worse. Absent such regulatory commitment, the risk premiums required by investors to compensate for this regulatory risk may well offset the potential ratepayer gains from shifting project risks onto suppliers.

The choices among the alternative agreement structures involve important questions for regulators over the assignment of costs arising from particular infrastructure investments, and their ability to impose cost-discipline on and engage in risk sharing with utilities and third-party power suppliers. This is illustrated in the figure, below, which identifies and compares various risks for a traditional rate-based investment and an agreement for incremental supply from a 3<sup>rd</sup>-party supplier. These risks include a project's development, permitting and construction-cost risk; regulatory risk; risk of recovery of original investment; fuel price risk; plant performance (operating) risk; and incremental capital additions risk.

### Comparison of Various Power Plant Investment and Operating Risks for a Traditional Rate-Based Investment and Third-Party Supply Contract



In practice, the appropriate cost-recovery and risk-allocation arrangements for a given resource and a given utility depends on many factors. Depending on the nature of the capital, operating and technology risks associated with a desired resource and the utility's existing portfolio of physical and financial assets, certain assignment of economic and financial risk may be more advantageous than others. There might be situations, for example, in which regulators determine that the presence of some type of profound risk and uncertainty would chill market participation in the absence of regulatory or other public policy decisions assigning to consumers the responsibility to bear some of this risk. This could occur for investment in certain advanced, capital-intensive, low-carbon technologies (such as a coal-fired integrated gasification combined cycle with or without carbon sequestration systems) which may involve technology, construction and operating risks that third-party suppliers are unwilling to undertake (or willing to undertake only at a price unacceptable to regulators). In such a case, the policy maker – whether a legislature or a regulator – might decide that it is important to include some mechanism by which consumers bear some of this risk.<sup>29</sup> This could take the form of a market-based approach for procuring renewables

(or renewable energy credits), with regulators determining the amount to purchase and the market determining the lowest-cost means to accomplish it. Thus, the variety of agreement structures depicted in the figures above provides regulators with significant flexibility in how they encourage needed infrastructure investments.

It is important for regulators to recognize, however, that risk-sharing can be achieved through arrangements between consumers and third-party suppliers, as well as the more traditional risk-sharing between consumers and utilities. For example, if regulators determined that consumers should bear certain technology risk, then the option to supply resources with that attribute and risk profile could be made available equally to the utility and to third parties.

Similarly, it may be useful for regulators to avoid prescribing certain types of agreement structures, so that third party suppliers can compete for the opportunity to supply and offer alternative agreement structures that they believe can provide the utility and its customers with the best value. Thus, properly structured and independently evaluated competitive procurements provide a constructive means to determine prudent resource outcomes for consumers. Competitive processes provide an important mechanism that allows the market to make offers with different risk sharing arrangements while still providing regulators with continued oversight of resource needs and decisions.

### **Closing observations**

This focus on incentives is a reminder of the importance of market forces in disciplining costs. Increases in output and performance by generating facilities whose operation has shifted from regulated to competitive markets attest to the potential of market forces to lower costs in the electricity industry. This is not to say that markets operate perfectly – something that the current capital market crisis makes abundantly clear. They need attentive oversight and regulation to assure that they are functioning well. But well-functioning competitive processes provide valuable attributes – choice, innovation, cost discipline, service quality, and so forth – which together provide benefits to consumers regardless of the overall regulatory structure of a particular jurisdiction. It is using these competitive mechanisms in conjunction with strong regulatory oversight that I believe is the best path forward in these uncertain and “interesting” times.

## End Notes<sup>30</sup>

---

<sup>1</sup> Apologies to Victor Mair, of the University of Pennsylvania, who explains that the Mandarin character for “crisis” is not intended to be the same as “danger + opportunity” even though “crisis” is composed of two characters whose separate meanings are “danger” and “opportunity.” <http://www.pinyin.info/chinese/crisis.html>.

<sup>2</sup> See N. Gregory Mankiw, “Economic View: That Freshman Course Won’t Be Quite The Same,” *The New York Times*, May 24, 2009. As Mankiw explains, “the teaching of basic economics will need to change in some subtle ways in response to recent events,” including “the challenge of forecasting. It is fair to say that this crisis caught most economists flat-footed. In the eyes of some people, this forecasting failure is an indictment of the profession. But that is the wrong interpretation. In one way, the current downturn is typical: Most economic slumps take us by surprise. Fluctuations in economic activity are largely unpredictable.” [www.nytimes.com/2009/05/24/business/economy/24view.html?ref=todaypaper](http://www.nytimes.com/2009/05/24/business/economy/24view.html?ref=todaypaper), accessed May 24, 2009.

<sup>3</sup> High prices of \$10.82 per mcf (in June 2008) and \$10.62 per mcf (in July 2008) exceeded the prior record-breaking prices in the months following Hurricanes Katrina and Rita (\$10.33/mcf in September 2008, and \$9.89/mcf in October 2008). Prices in November 2008 (\$5.97/mcf), December 2008 (\$5.87/mcf) and January 2009 (\$5.15/mcf) were the lowest same-month prices since 2003. EIA Monthly wellhead price of natural gas, 1-1-00 through 1-1-09, in \$ per mcf.

<sup>4</sup> Also, last year’s estimate of the average price of natural gas in 2009 was more than double the estimate made a year later. For example, the estimate for the average price of natural gas to the electric sector was \$9.15 per MMBtu (as estimated in May 2008) and \$4.30 per MMBtu (as estimated in May 2009). EIA, Short-Term Energy Outlooks, Table 7.a.

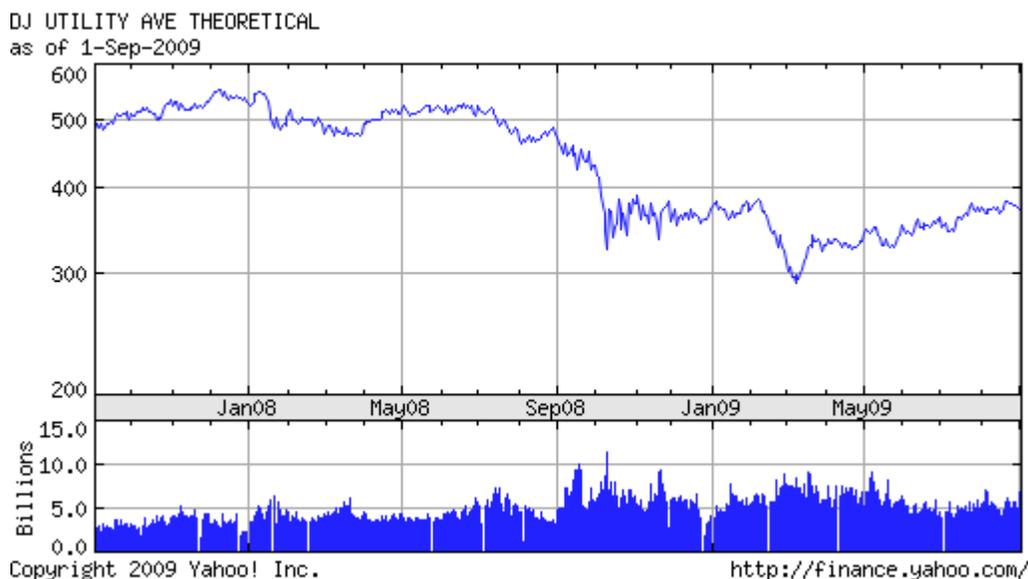
<sup>5</sup> EIA, Short Term Energy Outlook Data Tables, [http://www.eia.doe.gov/emeu/steo/pub/xls/STEO\\_m.xls](http://www.eia.doe.gov/emeu/steo/pub/xls/STEO_m.xls) (March 2009)

<sup>6</sup> The forecasts of electricity use in 2009 that were prepared during the Spring of 2009 show projections 10 percent lower than forecasts prepared as recently as a year before. In the figure, the forecast for 2009 prepared as of 3-2009 (shown in red) is 11-12 percent lower than the forecast for 2009 prepared one year previously (shown in blue). During the year ending 3/2009, retail sales were 2 percent lower than during the year ending 3/2008, and 5 percent lower than during the year ending 3/2006. See EIA, Monthly Electric Sales, from April of one year to the end of March of the following year (i.e., April 2000 through March 2008, and April 2008 through March 2009).

Further, in its most recent assessment for the summer months of 2009, the North American Electric Reliability Corporation (“NERC”) made the following observations: “Decreased economic activity across North America is primarily responsible for a significant drop in peak-demand forecasts for the 2009 summer season.... Compared to last year’s demand forecast, a North American-wide reduction of nearly 15 GW (1.8 percent) is projected. In addition, summer energy use is projected to decline by over 30 Terawatt hours (TWh), trending towards 2006 summer levels. While year-over-year reduction in electricity use is not uncommon — industrial use of electricity has declined in 10 of the past 60 years [fn in original], for example — it is critical that infrastructure development continues despite this decline. Based on the information provided as part of this assessment, most Regions have not yet experienced adverse impacts on infrastructure projects. However, WECC has

indicated that some generation and transmission projects have been deferred or cancelled, in part due to overall economic factors....” (NERC, Summer Assessment 2009, pages 1-3.)

<sup>7</sup> During one week alone in the Fall of 2008, electric industry securities lost a third of their value. The Dow Jones Utility Average index fell from 486.14 on August 28, 2008, to 324.57 on October 10, 2008, a decline of 34 percent in the overall market capitalization of the electric companies tracked by this index. (During this same period, the Standard & Poor’s 500 Index fell more than 30 percent – from 1,300.68 to 899.22 between August 28 and October 10.) The changes happened against a 12 month high of 552.74 in December 10 2007. Prices declined again in March 2009 to a low of 296.89,, but have rebounded somewhat since then. The index had a value of 367.26 on September 2, 2009. <http://finance.yahoo.com/q?s=%5EDJU>



<sup>8</sup> Capital markets are quite constrained due to the financial crisis facing the country. There are fewer financing options available and accessing capital has become more expensive. Utility companies’ credit ratings are dropping, with a higher percentage of downgrades to upgrades in the past year. (See, for example, S. Bonelli, Fitch Ratings, presentation to the Energy Bar Association, April 23, 2009.) In addition, tight credit markets have been significantly tougher for companies with poorer credit ratings. While widening credit spreads (e.g., the difference between bond yields and yields for 10-year treasury notes) have been particularly dramatic for bonds issued by companies with poorer credit ratings, they have been significant for all companies regardless of their credit-worthiness.

<sup>9</sup> Examples of utility regulatory policies that are undergoing change include:

- Adoption of revenue decoupling for utilities whose revenues are affected by the adoption of cost-effective energy efficiency (“EE”) measures. (“[E]ncouraging or mandating demand-side EE schemes without shielding the electric utility sector from financial harm is becoming an increasingly important credit issue due to the potential for decreased sales revenues and recovery or authorized costs. Historically, traditional rate design generally resulted in higher utility profits when energy sales increased, and lower utility profits when sale dropped. Amid the current recession and the significant increase in federal spending on EE, we believe that

utility sector credit quality may benefit from regulatory and public policy that addressed concerns over cost under recovery. Provisions like decoupling mechanisms may untie or lessen the correlation between a utility's profits and energy sales, mitigating potential utility financial risks." Tony Bettinelli, "When Energy Efficiency Means Lower Electric Bills, How Do Utilities Cope?" Standard & Poor's RatingsDirect, March 9, 2009. )

- Use of competitive procurement approaches for arranging supply for retail electricity customers. (See Susan Tierney and Todd Schatzki, "Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices," prepared for the National Association of Regulatory Utility Commissioners (NARUC), July 2008.)
- Use of long-term contracts and renewable portfolio standards to support investment in renewable energy generating facilities. (See: New York Independent System Operator, response to Question 15, [http://www.nyiso.com/public/webdocs/newsroom/whats\\_new/ResponsetoBrodskyCahillCompleteDocument.pdf](http://www.nyiso.com/public/webdocs/newsroom/whats_new/ResponsetoBrodskyCahillCompleteDocument.pdf).)
- Reliance on various capital-expenditure adjustment mechanisms and reliance of future test years (See Edison Electric Institute's 2008 Financial Review (Plus 2009 Developments), Annual Report of the U.S. Shareholder-Owned Electric Utility Industry," [http://www.eei.org/whatwedo/DataAnalysis/IndusFinanAnalysis/Documents/Financial\\_Review\\_full.pdf](http://www.eei.org/whatwedo/DataAnalysis/IndusFinanAnalysis/Documents/Financial_Review_full.pdf).)
- Adoption of forward capacity markets in Regional Transmission Organizations (see, for example, [http://www.epsa.org/forms/uploadFiles/FE8800000177.filename.FYI-4\\_Policy\\_Paper\\_-\\_Essential\\_Elements\\_Final.pdf](http://www.epsa.org/forms/uploadFiles/FE8800000177.filename.FYI-4_Policy_Paper_-_Essential_Elements_Final.pdf))

These are but a few of the approaches that are in discussion – and in use in many parts of the country.

<sup>10</sup> As of this writing, the House has approved H.R. 2454, "The American Clean Energy and Security Act." As described on the Committee's website, "This legislation is a comprehensive approach to America's energy policy that charts a new course towards a clean energy economy." The House bill differs in many respects from parallel bills currently introduced in the Senate.

<sup>11</sup> There are debates in the literature about whether a new carbon cap-and-trade program that is able to make it through Congress in the near term will produce greenhouse gas allowance prices high enough to induce investment in advanced technologies (e.g., advanced coal-fired generation with carbon capture and sequestration) that are capital intensive, emit low greenhouse gases and still not fully commercial viable. See, for example, National Commission on Energy Policy, "Ending the Energy Stalemate: A Bipartisan Strategy to Meet America's Energy Challenges," December 2004, <http://www.energycommission.org/ht/a/GetDocumentAction/i/1088>; Constantine Samaras, Jay Apt, Ines L. Azevedo, Lester B. Lave, M. Granger Morgan, and Edward S. Rubin, "Cap and Trade is Not Enough: Improving U.S. Climate Policy," March 2009. <http://www.epp.cmu.edu/httpdocs/Publications/ClimatePolicy.pdf>.

<sup>12</sup> Speaking of the entire country's situation during his Inaugural address in January 2009, President Obama said, "That we are in the midst of crisis is now well understood.... Our economy is badly weakened, ...and each day brings further evidence that the ways we use energy strengthen our adversaries and threaten our planet....The state of the economy calls for action, bold and swift, and we will act – not only to create new jobs, but to lay a new foundation for growth. We will build the roads and bridges, the electric grids and digital lines that feed our commerce and bind us together. ... We will harness the sun and the winds and the soil to fuel our cars and run our factories. ... All

this we can do. All this we will do.” Text of President Barack Obama's inaugural address on Tuesday, as delivered, *by The Associated Press* The Associated Press Tue Jan 20, 5:04 pm ET.

<sup>13</sup> “We know the country that harnesses the power of clean, renewable energy will lead the 21st century. And yet, it is China that has launched the largest effort in history to make their economy energy efficient. We invented solar technology, but we’ve fallen behind countries like Germany and Japan in producing it. New plug-in hybrids roll off our assembly lines, but they will run on batteries made in Korea. ... It is time for America to lead again. Thanks to our recovery plan, we will double this nation’s supply of renewable energy in the next three years. ... We will soon lay down thousands of miles of power lines that can carry new energy to cities and towns across this country. And we will put Americans to work making our homes and buildings more efficient so that we can save billions of dollars on our energy bills. But to truly transform our economy, protect our security, and save our planet from the ravages of climate change, we need to ultimately make clean, renewable energy the profitable kind of energy. So I ask this Congress to send me legislation that places a market-based cap on carbon pollution and drives the production of more renewable energy in America. ...” Remarks of President Barack Obama – As Prepared for Delivery - Address to Joint Session of Congress, Tuesday, February 24th, 2009. [http://www.whitehouse.gov/the\\_press\\_office/remarks-of-president-barack-obama-address-to-joint-session-of-congress/](http://www.whitehouse.gov/the_press_office/remarks-of-president-barack-obama-address-to-joint-session-of-congress/).

<sup>14</sup> On February 17, 2009, President Obama signed into law H.R. 1, the American Recovery and Reinvestment Act of 2009 (the “Act”).

<sup>15</sup> To underscore the array of uncertainties and forecasting challenges that affect decision-making in the industry, here is a list of several of the variables that routinely make investment decisions quite difficult:

- demand forecasting, given different economic outlooks and assumptions about both the penetration of electricity-using equipment and the effects of energy efficiency measures;
- fuel price forecasting, especially for fossil fuels;
- estimation of capital costs of different technologies, including not only large central-station generating plants (such as nuclear, advanced coal, centralized solar facilities) as well as renewable energy and distributed generating units (e.g., off-shore wind, roof-top solar);
- projecting performance characteristics (e.g., heat rates, construction costs, environmental emissions, availability of manufacturers’ guarantees) of advanced technologies not yet ready for commercialization;
- forecasting the effect of regulatory and policy change, especially relating to environmental requirements and non-traditional cost-recovery ratemaking mechanisms;
- future price of emissions allowances;
- on-peak reliability value and potential capacity factors of various technologies (e.g., advanced nuclear, wind, solar, coal with carbon capture and sequestration); and
- siting attitudes towards particular facilities (e.g., nuclear projects, coal plants, wind farms, transmission facilities, carbon sequestration projects).

Additionally, in today’s credit markets, there is the added risk of highly constrained access to and cost of capital. Many of these variables are discussed in more detail in the companion appendix document to this white paper (“Appendix Figures for the White Paper: Allocating Investment Risk in Today’s Uncertain Electric Industry: A Guide to Competition and Regulatory Policy During ‘Interesting Times,’” September 2009), which can be found on the EPISA website.

<sup>16</sup> “The desire of reward is one of the strongest incentives of human conduct; ...the best security for the fidelity of mankind is to make their interest coincide with their duty.” Alexander Hamilton, *The Federalist Papers* (essay series), 72, 21 March 1788.

<sup>17</sup> For example, see Matthew Barmack, Edward Kahn and Susan Tierney, “A Cost-benefit Assessment of Wholesale Electricity Restructuring and Competition in New England,” *Journal of Regulatory Economics*, May 12, 2006; Kira Fabrizio, Nancy Rose and Catherine Wolfram, “Do Markets Reduce Costs? Assessing the Impact of Regulatory Restructuring on U.S. Electric Generation Efficiency,” *American Economic Review*, Volume 97, No. 4, September 2007. See also, [http://www.nyiso.com/public/webdocs/newsroom/press\\_releases/2009/Power\\_Plant\\_Efficiency\\_Improved\\_with\\_Competition\\_04202009.pdf](http://www.nyiso.com/public/webdocs/newsroom/press_releases/2009/Power_Plant_Efficiency_Improved_with_Competition_04202009.pdf).

<sup>18</sup> See Susan Tierney and Todd Schatzki, “Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices,” prepared for the National Association of Regulatory Utility Commissioners (NARUC), July 2008.

<sup>19</sup> These historical “natural monopoly” conditions included economies of scale in distribution systems, where it was inefficient for multiple firms to install and operate parallel power lines on city streets and in large urban systems. As a consequence, monopoly firms could provide service more efficiently than a competitive market. In such a situation, regulation was viewed as essential to curb a monopoly’s natural inclination to abuse its market power. Over the last quarter of the 20<sup>th</sup> century, economic and technological changes in the generation portion of the electric industry eroded the natural monopoly conditions in the generation portion of the market.

<sup>20</sup> In the absence of markets – as occurs with regulated monopolies – the rate established by regulators serves as a proxy for price, with regulated rates serving to create prices that, to the extent possible, reflect those that would arise from a competitive market.

<sup>21</sup> Some utilities make investments under “performance-based rates,” which provides certain incentives for utilities to reduce cost. Even in most jurisdictions with performance-based rates, however, regulators and utilities still tend to rely on a model that places prudent, used and useful investment in rate base with the prospects of recovery of and on that investment through regulated rates. And even where utilities are entering into power plant investments for which they seek to receive traditional cost recovery (e.g., through inclusion of prudently incurred investment in rate base and through recovery of expenses associated with operating power plants in cost-based rates), they may use various markets and binding contracts with third parties to provide goods and services they need to provide service to consumers. When viewed most broadly, such competitively solicited contracts may include agreements with equipment suppliers or construction contractors, fuel supply agreements, and so forth.

<sup>22</sup> For example, many independent power producers have relied upon the existence of a power purchase agreement signed with a utility as a critical element of the package provided to prospective lenders to demonstrate the financial viability of their projects and to qualify for debt financing. The lenders have tended to view such contracts as lowering project risk, especially in light of a body of utility and contract law, utility regulation and court decisions that has substantially allowed for the recovery of the costs associated with such 3<sup>rd</sup>-party supply contracts by the utility in rates charged to consumers.

<sup>23</sup> Note that there are instances where utility regulators review a utility proposal “before the fact.” In these circumstances, the commission may review the question of whether the proposed project is needed and is least cost, whether to allow cost recovery, or both.

<sup>24</sup> Performance-based ratemaking with compensation tied to outcomes of interest to consumers. Some jurisdictions set rates for utilities under an approach designed to create incentives for the utility to conduct its utility business in an efficient fashion. This is accomplished by establishing a multi-year rate plan with periodic formulaic adjustments in rates. The rate adjustments are designed to create incentives for cost reduction by allowing the utility to share savings with consumers. Going forward, rates are then set pursuant to a schedule of planned adjustments tied to external benchmarks (such as changes in Consumer Price Index or other metrics). The rate plan serves as the framework through which shareholders and ratepayers both absorb risk.

<sup>25</sup> For a more detailed discussion of best practices in competitive procurements, see: Susan Tierney and Todd Schatzki, “Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices,” prepared for the National Association of Regulatory Utility Commissioners (NARUC), July 2008.

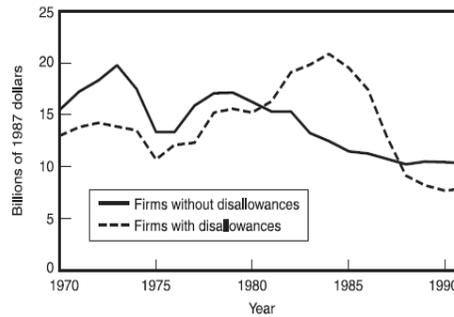
<sup>26</sup> For example, in Texas many competitive retail suppliers enter into bilateral contracts with generators to provide power supply.

<sup>27</sup> “Major cost disallowances by regulators of public utility investments have always been a possibility. In the mid-1980s, however, this possibility came to life in the form of roughly \$19 billion of disallowances of electric power plant investments that would otherwise have become part of the utilities’ rate bases....Cost disallowances have typically occurred within the context of establishing the utility’s rate base. The bulk of these disallowances have been categorized under the heading of management imprudence, but major disallowances have also occurred on the basis of excess capacity (which is not used and useful), and of economic value (in retrospect, alternative sources of power would have been cheaper). ...It was not until the mid-1980s that significant dollar volumes of cost disallowances began to occur in the electric utility industry.[footnote in the original]. Typical disallowances during the mid-1980s amounted to hundreds of millions of dollars, and in two cases (the Nine Mile Point 2 unit in New York and the Diablo Canyon plant in California) regulatory cost disallowances were \$2 billion or greater.[footnote in the original]. ... [W]e see that virtually all regulatory cost disallowances occurred beginning in the mid-1980s. Cumulatively, over 50 separate disallowances on 37 different generating units were observed in the sample period, with a total dollar volume of disallowance of over \$19 billion.[footnote in the original].” Thomas P. Lyon, and John W. Mayo, “Regulatory opportunism and investment behavior: evidence from the U.S. electric utility industry,” *RAND Journal of Economics*, Vol. 36, No. 3, Autumn 2005, pages 628–644. Figures from the Lyon/Mayo article (pages 630-633):

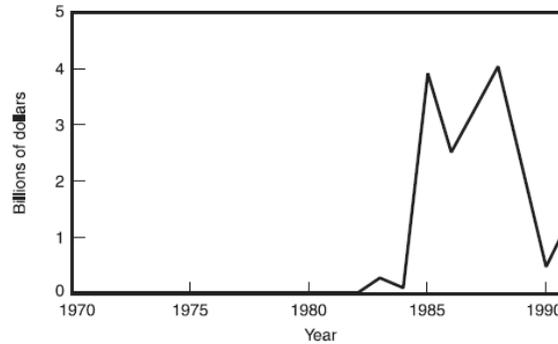
Real Investment by Electric Utilities, 1970–1991



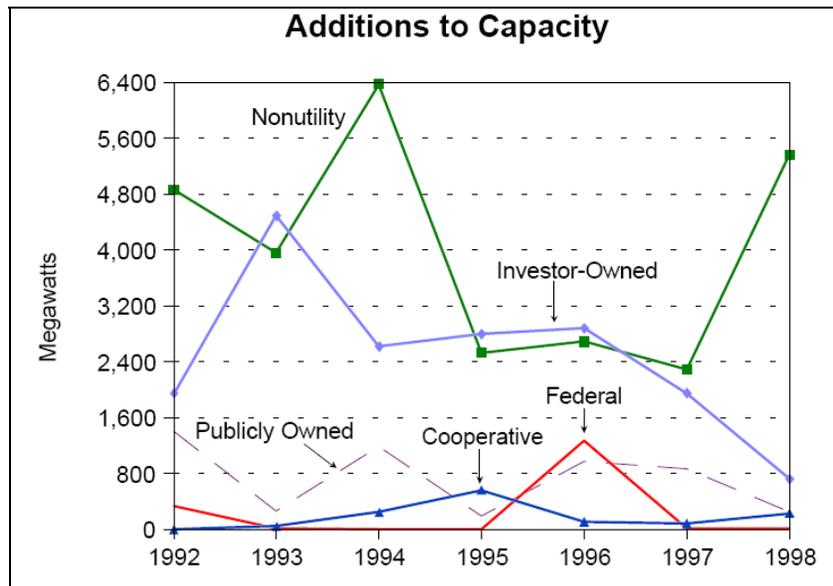
All Firms Real Investment by Electric Utilities, 1970–1991, By Firm Type



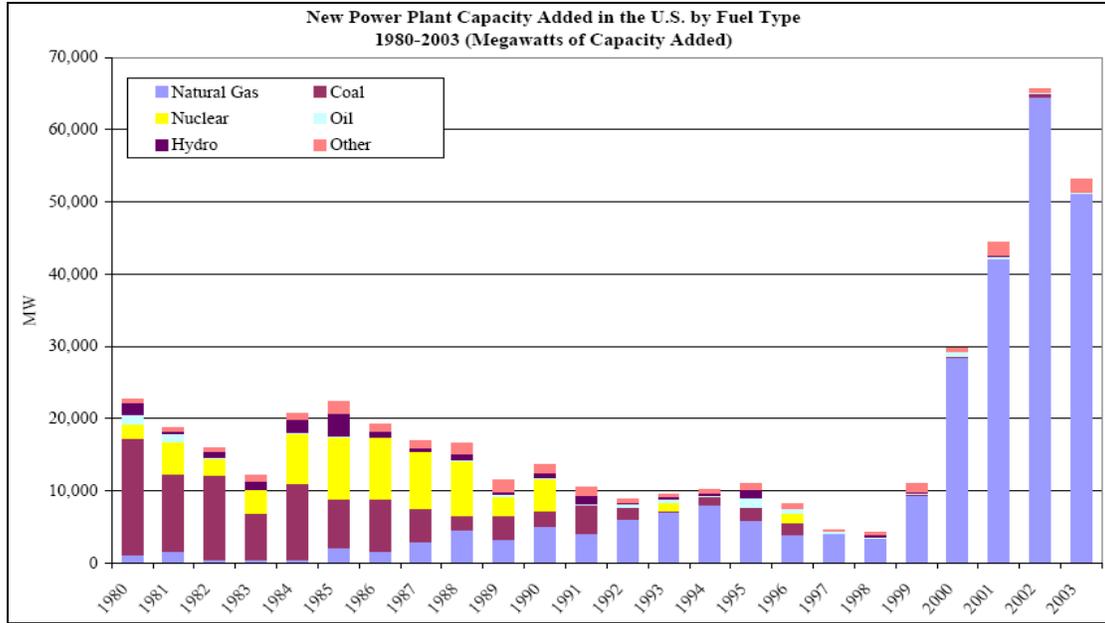
Dollar Values of Regulatory Disallowances, 1970–1991



<sup>28</sup> As noted by Lyon and Mayo, most of the costs that have been disallowed by regulators occurred during the past nuclear investment period. During the 1990s, and following upon the period of nuclear investment disallowances by regulators, most of the generating capacity that was added was done by non-utility generators. (See figure below for the Additions to Capacity (U.S.) during most of the 1990s. Source of figure: EIA, “The Changing Structure of the Electric Power Industry 2000: An Update,” October 2000, page 25.)



Most capacity added from 1998 to mid-2000s was natural-gas plants added by non-utility companies (see figure showing megawatts of capacity added by fuel type by year, including during the years of major nuclear additions (and disallowances) in the 1980s):



Source: Tierney, using Platts Basecase data.

<sup>29</sup> A clear example of the former can be found in the loan guarantee provisions of the Energy Policy Act of 2005. Title XVII's Loan Guarantee Program authorizes federal loan guarantees to be issued for projects with new or significantly improved technologies that avoid, reduce or sequester air pollutants and that are proposed by sponsors providing a reasonable assurance of repayment. Another example is Iowa's law that allows the Iowa Public Utility Commission to authorized regulators to determine the ratemaking treatment of costs of projects before construction begins. Norman Jenks, "Another perspective: The importance of being certain," *Electric Perspectives*, May/June 2003, [http://findarticles.com/p/articles/mi\\_qa3650/is\\_200305/ai\\_n9172919/](http://findarticles.com/p/articles/mi_qa3650/is_200305/ai_n9172919/).

<sup>30</sup> Susan Tierney is a Managing Principal at Analysis Group, Inc., in Boston, where she is an expert on energy policy, regulation and economics and focuses on the electric and gas industries. A consultant for a 14 years, she previously served as the Assistant Secretary for Policy at the Department of Energy (appointed by President Clinton), Massachusetts Secretary of Environmental Affairs (appointed by Governor Weld), Commissioner at the Massachusetts Department of Public Utilities (appointed by Governor Dukakis), and director of the Massachusetts Energy Facilities Siting Council. She recently co-led the Department of Energy Agency Review Team for the Obama/Biden Transition. She taught at the University of California at Irvine, and earned her Ph.D. and Masters degrees in regional planning at Cornell University. She has consulted to clients in business, industry, government, non-profit and other organizations. She serves on a number of boards of directors and advisory committees, including the National Commission on Energy Policy; chair of the Board of the Energy Foundation; a director of the Climate Policy Center/Clean Air-Cool Planet; member of the Advisory Council of the National Renewable Energy Laboratory, the Environmental Advisory Council of the New York Independent System Operator, and the WIRES' Blue Ribbon Commission on Transmission Cost-Allocation.